TECHNICAL REVIEW AND EVALUATION
ALLEGHENY ENERGY SUPPLY
AIR QUALITY PERMIT NO. 1001743

I. INTRODUCTION

This Class I (Title V) Permit is for the installation and operation of the La Paz Generating Facility, which will be located approximately 75 miles west of Phoenix, along Interstate Highway 10, in La Paz County, Arizona. This is a new "merchant" power plant project that will generate and sell electricity produced by natural gas combustion. The applicant originally submitted its permit application in October 2001. Revisions to the permit application were submitted in February, April, June, and August, 2002, which included numerous data submittals provided to the Arizona Department of Environmental Quality (ADEQ) to clarify the original permit application.

A. Company Information

Facility Name: Allegheny Energy Supply

Mailing Address: 4350 Northern Pike
Monroeville, PA 15146

B. Attainment Classification

The proposed source is to be located in an area that is designated attainment/unclassified for all criteria pollutants: total suspended particulate (TSP), particulate matter less than 10 microns in diameter (PM_{10}), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), lead (Pb), and ozone (O_3).

II. PROCESS DESCRIPTION

The La Paz Generating Facility is a natural gas-fired, combined cycle merchant power plant that will have the option of using either a Siemens-Westinghouse (SW) 501F combustion turbine generator (CTG) or a General Electric (GE) 7FA CTG. The facility will have a total rating of either 1080 Megawatts (MW) (nominal) with the SW501F, or 1040 MW with the GE7FA. It will consist of two power blocks rated at 540 MW each using the SW501F, or 520 MW each using the GE7FA.

The project is classified as Standard Industrial Classification Code 4911 and North American Industrial Classification System 221112, Fossil-Fuel Electric Power Generation. The primary processes at this facility consist of the following equipment:

A single power block for the SW501F configuration is made up of the following equipment:

- Two (2) SW CTGs equipped with dry low-nitrogen oxide (low-NO_x) combustors;
- Two (2) Heat Recovery Steam Generators (HRSGs) with supplemental duct firing at a rated heat capacity of 255.1 million British Thermal Units per hour (MMBtu/hr) (higher heating value (HHV));
- One (1) Steam Turbine Generator (STG) unit
- Two (2) selective catalytic reduction (SCR) systems for controlling nitrogen oxide (NO_x) associated with the CTG/HRSGs; and
- Two (2) oxidation Catalyst systems for controlling CO and volatile organic compounds (VOCs) - two associated with the CTG/HRSGs.

The support processes associated with the SW501F configuration will consist of the following equipment:

- Two (2) 10-cell (5 by 2) wet mechanical-draft cooling towers equipped with high efficiency drift eliminators for steam turbine condenser and equipment cooling;
- One Auxiliary Boiler with a maximum natural gas fuel burn rate of 55.34 MMBtu/hr and equipped with low-NOx burners;
- Two (2) diesel-fueled emergency generators each rated at 1,115 horsepower (hp);
- Two (2) diesel-fueled engines that drive the emergency fire water pumps rated at 250 hp;
- Main transformers; and
- Other ancillary equipment.

A single power block for the GE7FA configuration is made up of the following equipment:

- Two (2) GE7FA CTGs equipped with dry low-NO_x combustors;
- Two (2) HRSGs with supplemental duct firing at a rated heat capacity of 640 MMBtu/hr (HHV);
- One (1) STG unit;
- Two (2) SCR systems for controlling NO_x associated with the CTG/HRSGs; and
- Two (2) oxidation Catalyst systems for controlling CO and VOCs associated with the CTG/HRSGs.

The support processes associated with the GE7FA configuration will consist of the following equipment:

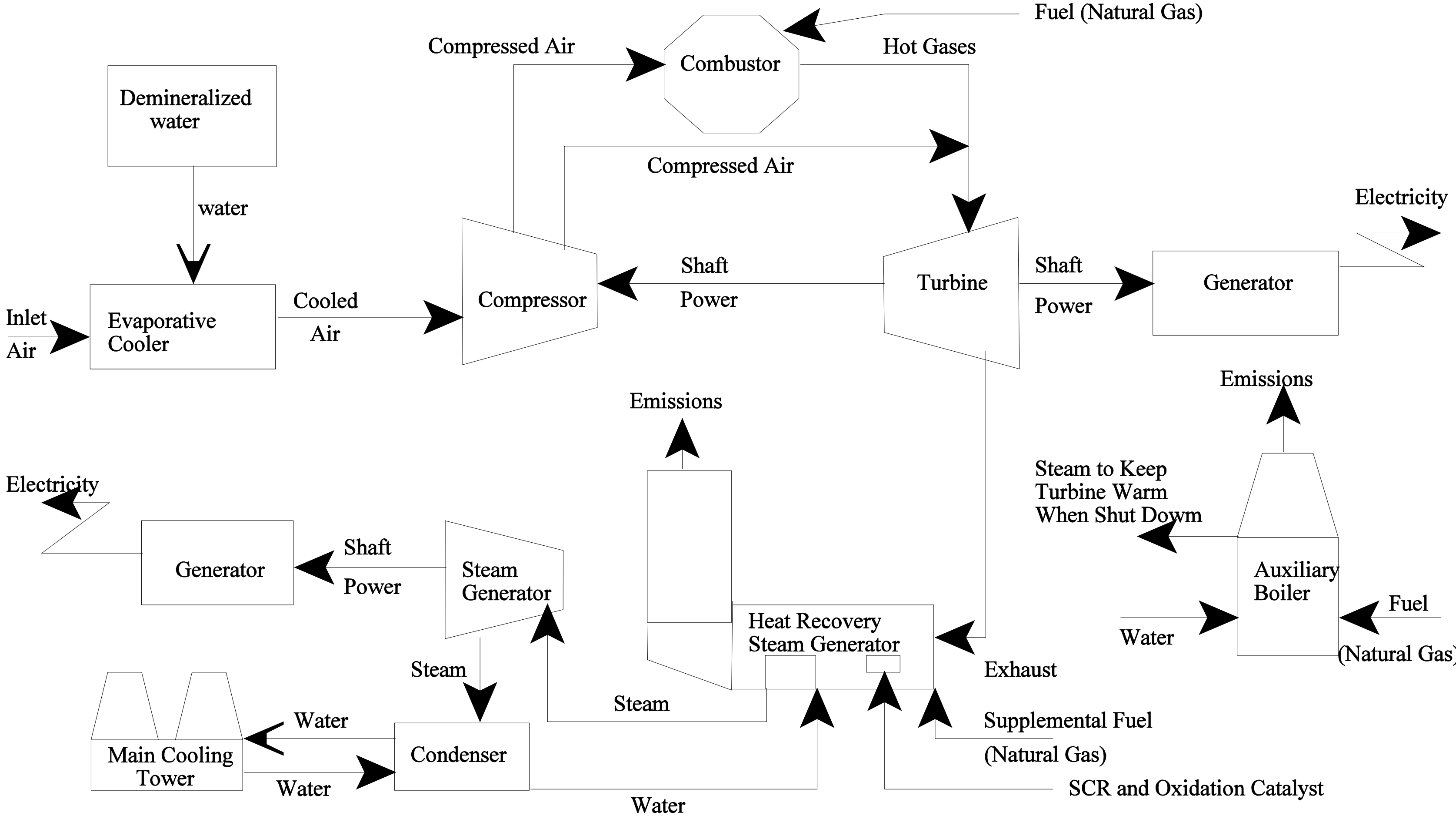
- Two (2) 10-cell (5 by 2) wet mechanical-draft cooling towers equipped with high efficiency drift eliminators for steam turbine condenser and equipment cooling;
- One Auxiliary Boiler with a maximum natural gas fuel burn rate of 41.0 MMBtu/hr and equipped with low-NOx burners;
- One (1) diesel-fueled emergency generator rated at 1,115 hp;
- Two (2) diesel-fueled engines to drive the emergency fire water pump each rated at 250 hp;
- Main transformers; and
- Other ancillary equipment.

A process flow diagram of the La Paz Generating Facility project is presented in Figure 1. The combustion turbine compresses chilled air which is mixed with natural gas and burned in the dry low-NO_x combustors. The resulting high temperature gases pass through the power turbine and exhaust to the HRSGs. The power turbine drives both the compressor and an electrical generator. The generators on each CTG are capable of producing 180 MW (International Standards Organization (ISO) conditions). The turbine exhaust gases are treated with an SCR system and an oxidation catalyst to further control NO_x, CO, and VOC emissions before being exhausted to the atmosphere.

The HRSGs are boilers that generate steam from the heat in the CTG exhaust gases. To increase overall output from the facility, supplemental (duct) firing of the HRSGs using natural gas may be performed so that additional steam can be produced for the STG. As a result, the HRSGs will generate additional emissions due to the firing of the ducts. The STGs are capable of generating 120 MW each. Because the STGs do not combust fuel, there are no air emissions from these units.

Low pressure, low temperature steam exhausted from the STG is condensed in the main condenser. The condensate is recycled for use in generating more steam. The condenser is cooled by the circulating water system that rejects waste heat to the atmosphere by evaporation in the cooling towers. Particulate matter that is entrained in the water vapor escaping from the cooling towers is controlled by high efficiency drift eliminators.

Figure 1. La Paz Generating Facility Process Flow Diagram



III. EMISSIONS

Tables 1 through 4 present the proposed short-term and annual emission limits for the units. The proposed permit limits are based on vendor and applicant data, and the application of control devices selected through the Best Available Control Technology (BACT) analysis.

A. Normal Operations - Hourly Emission Rates

Table 1 lists the combined cycle unit maximum hourly emission rates under any combination of full load operation and ambient temperatures. Table 1 also includes emissions with duct firing, which is to occur only after a combustion turbine has reached 100 percent load.

Table 1. Hourly Emission Limits During Periods Other than Start-up or Shutdown

Device	Hourly Emissions, Each CTG/HRSG, pound per hour (lb/hr)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle Systems (SW501F)	19.6	14.25	6.1	30.3	4.6
Combined Cycle Systems (GE7FA)	21.9	15.95	12.6	45.5	5.1

Notes:
1. The Combined Cycle System consists of one combustion turbine, one heat recovery steam generator with its associated duct burner, post combustion emission control systems, and exhaust stack.
2. PM_{10} emission rate includes condensible and filterable components.
3. Normal operation for the turbines are defined as loads above or equal to 75% of nameplate capacity, and start-up/shutdown are defined as loads below 75% of nameplate capacity.
4. Duct burning is limited to 1,530,600 MMBtu/year fuel rate for each Combined Cycle System using SW501F turbines.
5. Duct burner is limited to 2,587,248 MMBtu/year fuel rate for each Combined Cycle System using GE7FA turbines.

B. Start-up/Shutdown Operations - Hourly Emission Rates

Emissions of NO_x, CO, and VOCs from the combustion turbines during start-up/shutdown are significantly higher than during steady-state, full load operation. This is because combustion temperatures and pressures are rapidly changing during start-up/shutdown (which results in less efficient combustion and higher emissions), and because the dry low-NO_x combustors are operating in diffusion mode, not dry low-NO_x mode. In addition, pollution control systems such as oxidation catalysts are not as effective during the transitory temperature changes that occur during start-up and shutdown.

The higher NO_x, CO, and VOC start-up/shutdown emission rates must be included in the annual potential to emit (PTE) calculations, and are also considered in the air quality modeling analyses. The only pollutant that requires a separate start-up/shutdown short-term modeling analysis is CO, because it is the only one of these three pollutants with short-term air quality standards. For NO_x, the air quality standard is an annual standard, therefore the annual NO_x emission rate that is modeled must include total emissions from both normal operations and start-up/shutdown operations. Because of the CO and NO_x modeling requirements to demonstrate compliance with air quality standards and increments, separate start-up/shutdown emission limits have been established for CO and NO_x and are listed in

Table 2. Compliance with the start-up/shutdown CO and NO_x emission limits in Table 2 shall be determined using continuous emissions monitoring systems (CEMS).

Table 2. Hourly Emission Limits During Periods of Start-up or Shutdown

Device	Hourly Emissions, Each CTG/HRSG, lb/hr	
	NO_x	CO
Combined Cycle Systems (SW501F)	100	1131
Combined Cycle Systems (GE7FA)	116	1764

Notes:
1. Start-up is defined as the period between initiation of fuel flow until the electrical load of the Combustion Turbine increases to 75% or more of the nameplate capacity.
2. Shutdown is defined as the period beginning when the electrical load of a Combustion Turbine drops below 75% of nameplate capacity and ending when fuel flow has ceased.
3. Combined hours in both start-up and shutdown mode for each Combined Cycle System is limited to 783 hours per year.

Even though VOC emissions are higher during start-up/shutdown operations (and these higher emission estimates are included in the annual VOC emission calculations), it is not practical to establish VOC start-up/shutdown emission limits because of the difficulty in testing for compliance (Environmental Protection Agency (EPA) Reference Methods 25A and 18 manual stack tests are used for VOCs, which are very difficult to conduct during the non-steady-state conditions of startup/shutdown). In addition, a start-up/shutdown modeling analysis is not required for VOCs (there are no air quality standards for VOCs and the relationship between hourly VOC emission rates and ambient ozone concentrations is extremely difficult to determine). Therefore, separate VOC start-up/shutdown emission limits have not been established.

Because emissions of particulate matter (PM)/PM_{10} and SO_2 do not increase during start-up/shutdown, separate start-up/shutdown emission limits are not established for these pollutants.

C. Annual Allowable Emission Limits

Table 3 presents the maximum annual facility PTE considering all permitted sources. Annual operations will be limited by the specific limits on hours of operation for the various operating modes (normal, duct firing, start-up/shutdown). The total allowable emissions in Table 3 include emissions from the proposed emergency generator and fire pump engine, which will only be used for emergency purposes or for testing/maintenance and are limited to 500 hours of operation per year for each generator set. For the SW501F configuration, there are two generator sets which each consist of one emergency generator and one fire pump. For the GE7FA configuration, there is one generator set which consists of one emergency generator and two fire pumps.

At full load and 20 degrees Fahrenheit (°F) (the annual average temperature at the site), the heat input of the combustion turbines will be 1,985.42 MMBtu/hr for the SW501F turbines and 1795.9 MMBtu/hr for the GE7FA turbines. The duct burners heat input will be 255.1 MMBtu/hr (HHV) for the SW501F turbines and 640 MMBtu/hr (HHV) for the GE7FA turbines. Normal operation is defined by the applicant at loads above or equal to 75%. The applicant calculated emissions for the combined cycle units during operation at 100% load using 7,977 hours per year, including duct firing and 783 hours for startup and shutdown conditions. The startup and shutdown hours added to the 7977 hours of operation equal

8760 hours in one year.

Table 3a. Average Annual Emissions (SW501F)

Device	Average Annual Emissions, tons per year (TPY)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle System 1	113.2	220.6	47.7	132.7	20.1
Combined Cycle System 2	113.2	220.6	47.7	132.7	20.1
Combined Cycle System 3	113.2	220.6	47.7	132.7	20.1
Combined Cycle System 4	113.2	220.6	47.7	132.7	20.1
Cooling Towers (2)	N/A	N/A	N/A	46.4	N/A
Auxiliary Boiler	6.5	21.8	2.4	3.6	0.6
Diesel Emergency Generators and Fire Pumps	6.6	1.8	0.2	0.4	2.6
TOTAL	465.9	906.0	193.4	581.4	83.6

Note:
1. N/A = Not Available
2. NO_x emissions will be controlled using low-NOx burners and SCR.
3. CO and VOC emissions will be controlled using an oxidation catalyst.

Table 3b. Average Annual Emissions (GE7FA)

Device	Average Annual Emissions, tons per year (TPY)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle System 1	129.3	265.4	60.5	199.3	22.3
Combined Cycle System 2	129.3	265.4	60.5	199.3	22.3
Combined Cycle System 3	129.3	265.4	60.5	199.3	22.3
Combined Cycle System 4	129.3	265.4	60.5	199.3	22.3
Cooling Towers (2)	N/A	N/A	N/A	57	N/A
Auxiliary Boiler	4.9	16.2	1.8	2.7	0.4
Diesel Emergency Generator and Fire Pumps (1)	3.3	0.9	0.1	0.2	1.3
TOTAL	525.4	1078.7	243.9	857.1	90.9

Note:
1. N/A = Not Applicable
2. NO_x emissions will be controlled using low-NOx burners and SCR.
3. CO and VOC emissions will be controlled using an oxidation catalyst.

Start-up/shutdown for the turbines are defined as loads below 75%. The amount of time a unit has been shutdown will determine whether the subsequent start-up is hot, warm, or cold. According to information from the turbine manufacturer, a hot start-up occurs if a unit has been offline for less than 8 hours, a warm start-up if it has been offline between 8 and 48 hours, and a cold start-up if it has been offline for greater than 48 hours. The applicant calculated start-up/shutdown emissions based on 100 cold starts, 100 warm starts, 100 hot starts. Emissions per start-up and shutdown were provided by the turbine manufacturer. Based on the durations of the various start-ups and shutdown provided, the annual limit on combined hours in both start-up and shutdown mode for each turbine is 783 hours per year.

D. BACT and New Source Performance Standard (NSPS) Emission Limits

Additional emission limits or concentrations required by regulations (e.g., NSPS, BACT) are shown in Table 4 on the following page. No alternate operating scenarios have been proposed by the applicant.

IV. APPLICABLE REGULATIONS

There are two components to the New Source Review (NSR) permitting program codified in Article 4 of the ADEQ regulations: Prevention of Significant Deterioration (PSD) and Nonattainment NSR. The PSD program is applicable in areas that are attaining air quality standards (or are "unclassified"), and it is intended to prevent further deterioration of air quality in the area. Nonattainment NSR applies in areas that are exceeding air quality standards.

In order to trigger the applicability of either of these programs, the source must meet the definition of a major stationary source. As shown in Table 5, the La Paz Generating facility is a major source because it is a "categorical source" (as in Arizona Administrative Code (A.A.C.) R18-2-401) with potential emissions of a regulated pollutant above the 100 ton per year (tpy) threshold. Because the proposed location of the La Paz Generating facility is designated attainment/unclassified for all criteria pollutants, only applicability with the PSD permitting program must be evaluated. The PSD applicability significant emission rate thresholds are exceeded at the La Paz Generating facility for NO_x, CO, SO_2, VOC, and PM_{10}.

The PSD permitting program requirements are contained in A.A.C. R18-2-406 of the ADEQ regulations. The requirements include an analysis of BACT; an ambient air quality impacts analysis for increment consumption and National Ambient Air Quality Standards (NAAQS); a visibility and other air quality related values (AQRV) impact analysis for Class I wilderness areas; and an analysis of additional impacts, including growth, soils, vegetation, and visibility impairment.

A. Permitting Requirements

As described above, the proposed facility is a major source for NO_x, CO, VOCs, and PM_{10} under the PSD permitting program. The source is also a major source under A.A.C. R18-2-302 of the ADEQ regulations, which implement the Title V permitting requirements. ADEQ has a unitary permit program so that sources apply for a permit under NSR and Title V concurrently. The permit application submitted by Allegheny Energy Supply covers both the PSD and Title V programs.

Table 4. Additional BACT and NSPS Emission Limits

Device	Concentration or Rate Limits				
	NO_x	CO	VOC	PM_{10}	SO_2
Each Combustion Turbine Exhaust Operating in Conditions Other than Start-up	Determined by calculation[1]	--	--	--	SO_2 emissions <150 ppmvd or sulfur fuel content of <0.8% by weight [2]
Each Duct Burner Exhaust	0.2 lb/MMBtu[3] and 1.6 lb/MW-hr	--	--	0.03[4] lb/MMBtu	0.02[5] lb/MMBtu
Each Combined Cycle System Exhaust	2.5 ppmvd, 1-hour rolling average (subject to two-year demonstration period)	3.0 ppmvd 3-hour rolling average	3.5 ppmvd 3-hour rolling average	0.0188 lb/MMBtu for GE7FA turbines, or 0.0148 lb/MMBtu for SW501F turbines 3-hour rolling average	0.0021 lbs/MMBtu 3-hour rolling average

[1] Based on NSPS Subpart GG, 40 Code of Federal Regulations (CFR) 60.332(a)(1).
[2] Based on NSPS Subpart GG, 40 CFR 60.333(a).
[3] Based on NSPS Subpart Da, 40 CFR 60.44a(a) and 60.44a(d)(1).
[4] Based on NSPS Subpart Da, 40 CFR 60.42a(a)(1).
[5] Based on NSPS Subpart Da, 40 CFR 60.43a(b)(2).

"--" means that no additional concentration or rate limit is specified for that pollutant.

Notes:

1. Concentration limits are parts per million by volume dry (ppmvd) corrected to 15% oxygen on a dry basis.
2. Parts per million emission limit for NO_x is a 1-hour rolling average calculated from continuous monitors. This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit.
3. Emission limits for CO are 3-hour rolling averages calculated from continuous monitors. VOC, SO_2 and PM_{10} averaging times are consistent with the stack testing methods (three 1-hour averages).
4. Ammonia emissions associated with the SCR control system will be limited to 10.0 ppmvd on a 24-hour rolling average.
5. To monitor for compliance with 40 CFR Part 60 Subpart GG, NO_x emissions shall be calculated as required by 40 CFR 60.335(c)(1) unless the Combustion Turbines are installed with a controller programmed with an algorithm acceptable to the Administrator and Director that continuously corrects for variations in ambient humidity, temperature, and pressure yielding a relatively constant NO_x concentration when corrected to 15 percent oxygen, in which case the continuous emission monitoring data can be used without the 40 CFR 60.335(c)(1) correction.
6. When multiple or alternative limits apply, the most stringent limit governs.

Table 5a. Potential to Emit (SW501F) and Applicability Thresholds

Pollutant	Potential Emissions (TPY)	Major Source Threshold (TPY)	Significance Level for PSD (TPY)	PSD Applicable?
NO_x	465.9	100	40	Yes
CO	906.0	100	100	Yes
VOC	193.4	100	40	Yes
PM_{10}	581.4	100	15	Yes
SO_2	83.6	100	40	Yes

Table 5b. Potential to Emit (GE7FA) and Applicability Thresholds

Pollutant	Potential Emissions (TPY)	Major Source Threshold (TPY)	Significance Level for PSD (TPY)	PSD Applicable?
NO_x	525.4	100	40	Yes
CO	1078.7	100	100	Yes
VOC	243.9	100	40	Yes
PM_{10}	857.1	100	15	Yes
SO_2	90.9	100	40	Yes

1. *Title V*

As a major source for Title V, the proposed La Paz Generating facility is required to obtain a Class I (Title V) permit. The permit application and its supplements submitted by Allegheny Energy Supply list applicable requirements and contain compliance information, as well as a certification of compliance, which are all required as part of a Title V permit application. Title V includes the specification of appropriate monitoring requirements and, as outlined in Section VI of this document, monitoring provisions are included in the permit.

2. *PSD*

The facility will have potential emissions above the PSD significance thresholds for NO_x, CO, VOC, SO_2 and PM_{10}. As a PSD major source, the facility is required by A.A.C. R18-2-406 to obtain a PSD permit. As explained in this Section, the PSD requirements codified at A.A.C. R18-2-406 are applicable for these pollutants. The requirements include a determination of BACT for NO_x, CO, VOC, SO_2 and PM_{10}, an analysis of the air quality impact of the project, and additional impacts, which are discussed in Sections V and VII respectively.

B. Other Applicable Requirements

1. *New Source Performance Standards (NSPS)*

Federal authority for NSPS requirements (delineated in 40 CFR Part 60) has been delegated to ADEQ, and Article 9 of the ADEQ regulations adopted the NSPS by reference. For the proposed project, the combustion turbines are subject to NSPS Subpart GG, the duct burners at the heat recovery steam generators are subject to Subpart Da, and the Auxiliary Boiler is subject to Subpart Dc.

NSPS Subpart GG, *Stationary Gas Turbines*, is applicable to turbines with heat input capacities greater than 10 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart GG for the proposed turbines:

a) §60.332, Standard for NO_x, includes an equation to calculate allowable NO_x emissions in parts per million (ppm). From the equation, the nominal NO_x emission rate for the proposed turbines is 75 ppm @ 15% O_2 (without correction for thermal efficiency), which is much higher than the permitted rate.

b) §60.333, Standard for SO_2, specifies SO_2 emissions <150 ppmvd or a sulfur fuel content of <0.8% by weight. Natural gas is the only fuel that will be combusted by the proposed project and it is inherently low in sulfur. Compliance with this standard will be met by burning only pipeline quality natural gas.

c) §60.334, Monitoring of Operations, requires monitoring of sulfur and nitrogen content of the fuel being fired in the turbine on a daily basis. A custom schedule for determination of these values may be developed based on the design and operation of the turbines and the characteristics of the fuel supply. The custom schedule shall be substantiated with data and must be approved by the Director before it can be used to comply with §60.334(b).

d) §60.335, Test Methods and Procedures, specifies the methods to determine the nitrogen and sulfur contents of the fuel, and how to determine compliance with the NO_x and SO_2 standards. Appropriate test methods are also discussed.

NSPS Subpart Da, *Electric Utility Steam Generating Units*, is applicable to duct burners at heat recovery steam generators with heat input capacities greater than 250 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart Da for the proposed duct burners:

a) §60.42a(a)(1), Standard for PM, specifies that PM not exceed 0.03 lb/MMBtu heat input. §60.42a(b) requires opacity to be $\leq$ 20% (6-minute average), except for one 6-minute period per hour not exceeding 27%.

b) §60.43a(b)(2), Standard for SO_2, specifies that SO_2 not exceed 0.20 lb/MMBtu.

c) §60.44a(a)(1), Standard for NO_x, specifies that NO_x (expressed as NO_2) not exceed 0.20 lb/MMBtu heat input, based on a 30-day rolling average basis. For a new source, §60.44a(d)(1) specifies that NO_x (expressed as NO_2) not exceed 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average. Compliance provisions for duct burners subject to §60.44a(a)(1) and §60.44a(d)(1) are specified in §§60.46a(j) and (k).

d) From §60.46a(c), Compliance Provisions, these standards apply at all times except start-up, shutdown, and malfunction.

e) §§60.47a(a) and (b), Emission Monitoring, states a continuous monitoring system (CMS) is not required for opacity or SO_2 if gaseous fuel is the only fuel combusted. As per §60.47a(o) duct burners subject to §§60.44a(a)(1) or (d)(1) do not require the installation of CMS for NO_x; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; or a continuous flow monitoring system.

f) §§60.48a(b), (c), and (d), Compliance Determination Procedures and Methods, specify the methods to determine compliance for PM, SO_2, and NO_x. Alternative methods are provided in §60.48a(e).

g) §60.49a(a), Reporting Requirements, requires submittal of initial performance test data for SO_2, NO_x, and PM.

h) §60.49a(b), Reporting Rquirements, specifies the submittal of the information listed for SO_2 and NO_x.

i) §60.49a(g), Reporting Requirements, requires the submittal of a signed statement regarding the items listed.

j) §60.49a(h), Reporting Requirements, defines excess emissions for opacity and requires quarterly reporting.

k) §60.49a(i), Reporting Requirements, requires submittal of semiannual reports.

l) §60.49a(j), Reporting Requirements, states that a source may submit electronic reports in lieu of the written reports required under paragraphs (b) and (h).

Because the BACT requirements for Allegheny will mandate much lower emissions rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

NSPS Subpart Dc, *Small Industrial-Commercial-Institutional Steam Generating Units*, is applicable to boilers with heat input capacities between 10 and 100 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart Dc for the proposed auxiliary boiler:

a) Note that the SO_2 and PM emission requirements in Subpart Dc only apply to sources combusting coal, oil, or wood. Also, there are no requirements in Subpart Dc for NO_x.

b) §60.48c(a), Reporting and Recordkeeping Requirements, requires the submittal of notification of the date of construction, anticipated date of start-up, and date of actual start-up.

c) §60.48c(g), Reporting and Recordkeeping Requirements, requires the submittal of the amounts of fuel combusted each day.

d) §60.48c(j), Reporting and Recordkeeping Requirements, specifies the reporting period as 6 months.

Because the BACT requirements for Allegheny will mandate much lower emissions rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

2. *Accidental Release*

Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Applicability is determined by comparing the amount of a listed substance on-site at a facility to its threshold quantity. Allegheny has proposed using ammonia in association with the SCR NO_x control system. At the time the application was submitted, the design specifications for the SCR system was not complete, thus, the type, concentration, and quantity to be stored on-site was not known. If more than a threshold quantity (20,000 pounds for aqueous or 10,000 pounds for anhydrous) will be stored on-site, this will trigger the risk management planning requirements. A Risk Management Plan is required by the date on which a regulated substance is first present above the threshold quantity. Consequently, a Risk Management Plan for the storage and use of ammonia will be required before ammonia in excess of the threshold can be stored on-site.

In addition to a Risk Management Plan, under Section 112(r)(1) of the Clean Air Act, Allegheny also has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

3. Acid Rain

The combined cycle units are considered Stage II affected units under the Title IV Acid Rain Program and an Acid Rain permit must be obtained prior to operation. As part of a supplement to its permit application Allegheny submitted an Acid Rain permit application. The proposed permit serves as a combined PSD, Title IV, and Title V permit. The permitted emission limits, monitoring, recordkeeping, and reporting requirements of the proposed permit incorporate the applicable Acid Rain provisions of 40 CFR Parts 72, 73, and 75.

As a new plant, Allegheny does not hold SO_2 allowances and will have to obtain such allowances to sufficiently cover its previous year's emissions as of the allowance transfer deadline. Emission limits for NO_x are not applicable to the project because the Acid Rain provisions only apply to coal-fired units. Monitoring requirements from 40 CFR Part 75 are discussed in Section VI.

C. Regulatory Streamlining

The proposed La Paz Generating facility is subject to requirements under NSPS that are less stringent than those required in the proposed permit as a result of BACT. The permit has been drafted to reflect the more stringent requirements. The following analysis demonstrates the permit streamlining. Table 6 summarizes the requirements and demonstrates that the streamlined permit conditions are more stringent.

From NSPS Subpart GG, the emission limit for NO_x from the combustion turbines is established in §60.332(a)(1) as 0.01% by volume at 15% O_2, which corresponds to 75 ppmvd @15% O_2 (without correction for thermal efficiency). NO_x emissions from the turbines will be controlled by dry low-NO_x combustors and further controlled by an SCR system. The BACT analysis results in an emission rate for NO_x of 2.5 ppmvd @ 15% $O_{2,}$ which is more stringent than the NSPS Subpart GG requirement. This emission limit may be reduced to 2.0 ppmvd after the first two years of operation based on the NO_x demonstration required by the permit. NSPS Subpart Da establishes an emission limit for NO_x of 0.20 lb/MMBtu for the duct burners. The total NO_x emission rate for each combined cycle system equates to 0.009 lb/MMBtu, which is also more stringent than the NSPS requirement.

The emission limit for SO_2 in NSPS Subpart GG is either a fuel sulfur content of 0.8% by weight or 150 ppmvd. Pipeline quality natural gas is the only fuel to be combusted in the turbines and it is inherently low in sulfur with a maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf). This equates to a weight percent of sulfur of 0.0024%, which is much lower than the NSPS limit of 0.8% by weight. NSPS Subpart Da establishes an SO_2 emission limit of 0.2 lb/MMBtu for the duct burners. The total SO_2 emission rate for each combined cycle system equates to 0.0021 lb/MMBtu, which is more stringent than the NSPS.

As per Part 75 continuous monitoring is required for NO_x, Oxygen (O_2) (or CO_2), and fuel flow. Test methods specified in the permit are more broad and inclusive of the NSPS-specified method. Recordkeeping and reporting requirements in the permit are as stringent as the NSPS.

Table 6. Permit Streamlining Analysis

Citation	Requirements	Proposed Permit Condition	Comparable Level of Stringency
Emission Limits	Turbine: NO_x: 40 CFR 60.332(a)(1), turbine < 75 ppmvd SO_2: 40 CFR 60.333(a), fuel content <0.8% by weight Duct burners: NO_x: 40 CFR 60.44a(a)(1) and (d)(1), $\leq$ 0.20 lb/MMBtu, 1.6 lb/MW-hr SO_2: 40 CFR 60.43a(b)(2), $\leq$ 0.2 lb/MMBtu PM: 40 CFR 42a(a)(1) and (b), $\leq$ 0.03 lb/MMBtu, opacity $\leq$20% (6-min avg)	Combined cycle units: BACT: 2.5 ppmvd @ 15% O_2, 1 hour average* Maximum allowable sulfur content of natural gas 0.75 grains/100 dscf, equates to 0.004 lb/MMBtu PM emission rate equates to 0.01 lb/MMBtu, opacity $\leq$10% (6-min avg)	Permit more stringent
Monitoring	40 CFR Part 75: CEMS for NO_x and O_2 (or carbon dioxide (CO_2)), and CMS for fuel flow 40 CFR 60.334(b), sulfur and nitrogen content of the fuel, daily or custom schedule	CEMS for NO_x and O_2 (or CO_2), and CMS for fuel flow Federal Energy Regulatory Commission-approved agreement for sulfur content	Permit as stringent
Testing	40 CFR 60.8, 60.335(b) and 40 CFR 60.48a, initial source testing and as required by Administrator	Initial performance testing and compliance via CEMS	Permit as stringent
Recordkeeping	40 CFR 60.49a(b), daily records for reporting	Fuel flow monitor and fuel usage records, records of emission rates and CEMS data	Permit as stringent
Reporting	40 CFR 60.7, 60.334(c), 60.49a(h), excess emissions 40 CFR 60.49a(a), performance test data 40 CFR 60.49a(b), reports for SO_2 and NO_x 40 CFR 60.49a(g), signed statement 40 CFR 60.49a(i), semi-annual reports	Semi-annual reports, excess emissions, performance test data, notifications	Permit as stringent

* This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit.

V. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD regulations under Title I of the Federal Clean Air Act and A.A.C. R18-2-406.A, and the BACT requirements under those regulations, are applicable to the La Paz Generating facility for NO_x, CO, VOC, SO_2 and PM_{10}. The term "best available control technology" is defined in the ADEQ regulations as follows:

> "an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification."

A "top-down" approach is recommended for determining BACT, and the analyses are to be performed on a source-by-source and pollutant-by-pollutant basis. This approach essentially ranks potential control technologies for each pollutant in order of effectiveness and ensures that the best technically and economically feasible option is chosen. As described in the Environmental Protection Agency's (EPA) *New Source Review Workshop Manual*, draft (final document never published), October 1990, the general methodology of this approach is as follows:

1. Identify potential control technologies, including combinations of control technologies, for each pollutant subject to PSD review.
2. Evaluate each control technology for technical feasibility; eliminate those determined to be technically infeasible.
3. Rank the remaining technically feasible control technologies in order of control effectiveness.
4. Assume the highest ranking technically feasible control represents BACT, unless it can be shown to result in adverse environmental, energy, or economic impacts.
5. Select BACT.

The NSR Workshop Manual also notes that, to complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be met on a continual basis at all levels of operation, must demonstrate protection of short term ambient standards, and must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, the permit must specify a reasonable compliance averaging time, consistent with established reference methods, and must include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

As required by PSD regulations, Allegheny will be using air pollution control techniques for each pollutant subject to review that have been analyzed and are deemed to be "best available control technology," to control emissions from its emitting sources. The applicant provided a BACT analysis in its initial application and subsequent revisions. The analyses have been reviewed by ADEQ and the results are summarized below for each of the emitting units.

A. Combined Cycle Systems

The CTG/HRSG units will be equipped with an SCR system and low-NO_x combustors to control NO_x emissions to 2.5 parts per million by volume dry (ppmvd) @ 15% oxygen (O_2) (1-hour average). However, the SCR system will be designed to meet 2.0 ppmvd. This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit. An oxidation catalyst will control CO and VOC emissions. Combustion controls will mitigate emissions of PM_{10}. Emissions of sulfur oxides (SO_2 and sulfur trioxide (SO_3)) will be limited by the maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf) and 0.0021 lb/MMBtu heat input. These limits are the same for either the SW501F or the GE7FA, but a BACT analysis was required for both turbines.

1. Particulate Matter Less than 10 Microns (PM_{10})

PM_{10} is a Clean Air Act regulated pollutant defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as in-stack or "filterable" and condensible PM. The amount of both filterable and condensible PM_{10} emissions from natural gas-fired combustion turbines should be very small relative to the total exhaust flow. Vendor data on expected PM_{10} emission rates are designed to allow for the high level of test error inherent in sampling for an extremely small quantity of PM_{10} in a very large exhaust flow. In order to reduce the amount of variability/error, longer sampling times than are normally used by stack testers during compliance testing can be used.

There are no known applications of add-on controls for the purpose of controlling PM_{10} from natural gas-fired units, because this fuel has little if no ash that would contribute to the formation of PM or PM_{10}. Table 7 lists PM_{10} emission rates and controls contained in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for other recently permitted similar sources. The applicant has demonstrated that the use of good combustion practices and natural gas represents BACT for PM_{10}.

2. *Nitrogen Oxides (NO_x)*

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion.

The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment (i.e., NO_x is removed from the exhaust stream after it is generated). The applicant considered a number of measures for the control of NO_x emissions from the proposed project, including both in-combustor controls, such as water (or steam) injection, and the use of dry low-NO_x combustors. SCR, Selective Non-Catalytic Reduction (SNCR), $SCONO_x$, and XONON were considered as post-combustion NO_x control systems. A comparison of the control systems proposed by the applicant and previously permitted control systems taken from the RACT/BACT/LAER Clearinghouse (RBLC) is presented in Table 8.

For large gas turbines such as those proposed, water and steam injection have been largely superseded by dry low-NO_x (DLN) combustors, due to the superior emission control performance and increased efficiency. DLN combustors are also effective in achieving lower NO_x emission levels without the need for large volumes of purified water. Both dry low-NO_x burners and water injection result in higher VOC and CO emissions than uncontrolled turbines, but these effects will be minimized by high combustion temperatures, adequate excess air, and good air-to-fuel mixing during combustion.

Among post-combustion control systems, the XONON catalytic system was rejected because it is not technically feasible. XONON is an emerging technology and is not commercially available at this time for CTGs of the size proposed for this project.

SNCR was also rejected as a possible control system because the technology requires gas temperatures in the range of 1200° to 2000°F, and the exhaust temperature for the proposed turbines, i.e. 600ºF, is below the minimum SNCR operating temperature.

Table 7. CTG/HRSG BACT Comparison for PM_{10}

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		La Paz Generating Facility	CTG/HRSG	Good Combustion	0.0148/ 0.0188	lb/MMBtu	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	Good Combustion	10.7	lb/hr	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating Station	CTG	Combustion Controls	11	lb/hr	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	18	lb/hr	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	Use of Natural Gas	18	lb/hr	BACT
OK-0036	NG	Stephens Energy Facility	CTG/HRSG	NG	19	lb/hr	BACT
FL-0225	8/14/01 Dft	El Paso Broward Energy Center	CTG/HRSG	Combustion Controls	20	lb/hr	BACT
FL-0226	9/11/01 Dft	El Paso Manatee Energy Center	CTG/HRSG	Combustion Controls	20	lb/hr	BACT
FL-0227	9/11/01 Dft	El Paso Belle Grade Energy Center	CTG/HRSG	Combustion Controls	20	lb/hr	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	21	lb/hr	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Good Combustion Control	24	lb/hr	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Good Combustion Control	30.4	lb/hr	BACT
MI-0256	1/12/01	Covert Generating Co LLC	CTG/HRSG	Good Combustion	33.8	lb/hr	BACT
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG/HRSG	Good Combustion Practices	0.0065	lb/MMBtu	BACT
AL-0141	4/10/00	GPC-Goat Rock Combined Cycle Plant	CTG/HRSG	Efficient Combustion	0.009	lb/MMBtu	BACT
Al-0162	1/8/01	Autaugaville Combined Cycle Plant	CTG/HRSG	Good Combustion	0.009	lb/MMBtu	BACT
RI-0019	5/3/00	Reliant Energy Hope Gen. Facility	CTG/HRSG		0.009	lb/MMBtu	BACT
AL-0167	1/26/01	Calhoun Power Company I, LLC	CTG	Good Combustion Practices	0.01	lb/MMBtu	BACT
MO-0053	1/1/96	Hawthorne Generating Station	CTG		0.01	lb/MMBtu	BACT
MO-0056	3/30/99	Associated Electric Cooperative	CTG	Good Combustion	0.01	lb/MMBtu	BACT
OK-0041	1/19/00	McClain Energy Facility	CTG/HRSG	Clean Fuels	0.01	lb/MMBtu	BACT
MS-0040	12/31/98	Mississippi Power Plant	CTG		0.011	lb/MMBtu	BACT
AL-0143	3/3/00	AEC-McWilliams Plant	CTG/HRSG	Good Combustion	0.012	lb/MMBtu	BACT
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion	0.012	lb/MMBtu	BACT
AL-0169	2/5/01	Blount Megawatt Facility	CTG	Good Combustion Practices	0.013	lb/MMBtu	BACT
AR-0035	8/24/00	Panda - Union Generating Station	CTG	Clean Fuels, Proper Operation	0.014	lb/MMBtu	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	Efficient Combustion	0.015	lb/MMBtu	BACT
MO-0058	5/9/00	Audrain Generating Station	CTG	Good Combustion	0.016	lb/MMBtu	BACT
AL-0132	11/29/99	Tenaska Alabama Generating Station	CTG/HRSG	Efficient Combustion	0.02	lb/MMBtu	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	Clean Fuels	0.02	lb/MMBtu	BACT

Table 8. CTG/HRSG BACT Comparison for NO_x

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		La Paz Generating Facility	CTG/HRSG	SCR, Dry Low NOx Burner	2.5/2.0	ppmvd	BACT
CA	10/27/00	Otay Mesa	CTG/HRSG	SCONOx or SCR	2	ppmv	BACT
CT-0148	6/22/99	Lake Road Generating Company	CTG	SCR, Dry Low NOx Burner	2	ppmv	LAER
MA-0024	**4/16/99**	**ANP Blackstone**	**CTG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**LAER**
MA-0025	**8/4/99**	**ANP Bellingham**	**CTG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**LAER**
MA-0029	**9/29/99**	**Sithe Mystic Development**	**CTG/HRSG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**BACT**
RI-0019	**5/3/00**	**Reliant Energy Hope Gen. Facility**	**CTG/HRSG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**BACT**
AZ	**4/30/02**	**Gila Bend Power Generation Station**	**CTG/HRSG**	**SCR, Dry Low NOx Burner**	**2.5/2.0**	**ppmv**	**BACT**
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	12/2/99	Sutter Power Plant	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	5/30/01	Contra Costa	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	12/18/01	Elk Hills Power Project	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0225	8/14/01 Dft	El Paso Broward Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0226	9/11/01 Dft	El Paso Manatee Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0227	9/11/01 Dft	El Paso Belle Grade Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
NH-0011	4/26/99	AES Londonderry, LLC	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
NH-0012	NG	Newington Energy LLC	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	LAER
PA-0160	10/10/00	Calpine Construction Finance Co.	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	LAER
WA-0288	9/4/01	Longview Energy Development	CTG/HRSG	SCR	2.5	ppmv	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	SCR, Dry Low NOx Burner	3	ppmv	LAER
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	SCR	3	ppmv	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	SCR	3	ppmv	BACT
AR-0035	8/24/00	Panda - Union Generating Station	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
AR-0040	12/29/00	Duke Energy Hot Springs	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating STN	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
OK-0036	NG	Stephens Energy Facility	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
WI-0174	9/20/00	Badger Generating Co LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT

The SCR process is a post-combustion control technology in which injected ammonia (NH_3) reacts with NO_x in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_x emission reduction is a function of the catalyst volume and ammonia-to-NO_x (NH_3/NO_x) ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesired increased levels of unreacted NH_3 (called ammonia slip).

SCR has been demonstrated to be effective at numerous installations throughout the United States. Typically SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines and duct burners can be controlled.

$SCONO_x$ is another type of post-combustion control. The $SCONO_x$ system uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_x and CO. The $SCONO_x$ system does not use a reagent such as ammonia but instead utilizes natural gas as the basis for a proprietary catalyst regeneration process. The nitrogen oxide (NO) present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of nitrogen (N_2) and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no oxygen (O_2) present during this step. The CO present in the flue gas is oxidized to carbon dioxide (CO_2) as part of the $SCONO_x$ process.

From the analysis, the highest ranking technically feasible control for NO_x is considered to be the use of either SCR or $SCONO_x$ in conjunction with dry low-NO_x combustors. An analysis of the cost-effectiveness for $SCONO_x$ at 2.0 and 2.5 ppmvd at 15% O_2, and SCR at 2.0 and 2.5 ppmvd at 15% O_2 was used to determine the highest ranking, economically feasible control. Note that $SCONO_x$ also controls CO and does not require ammonia, and these factors were taken into account in the cost-effectiveness analysis.

The cost-effectiveness of $SCONO_x$ when compared to SCR results in $SCONO_x$ being considered not economically feasible. The total dollar per ton and incremental cost-effectiveness of SCR at NO_x levels of 2.5 and 2.0 ppmvd at 15% O_2 were also investigated. Cost data for the two levels of control for SCR was provided by the applicant in the June 24, 2002 Addendum for the GE configuration, and in the June 7, 2002 data submittal for the SW configuration. The cost analyses were not revised and 2 ppm NO_x was determined to be economically feasible. Given the averaging times that are used for the compliance of this limits, it is still unclear whether this limit can be met on a one hour rolling average.

After considering the available data, and the emission limits for other recently permitted similar projects, ADEQ concludes that DLN combustors in combination with an SCR control system that reduces NO_x to 2.0 ppmvd at 15% O_2 represents BACT for the CTG/HRSG. The emission limit is initially proposed at 2.5 ppmvd (1-

hr average) with a demonstration period that may reduce the emission limit to 2.0 ppmvd (1-hr average) after the first two years of operation based on the NO_x demonstration required by the permit. ADEQ is including the two-year demonstration period given that 1) the 2.0 ppmvd NO_x BACT limit has only recently been demonstrated, 2) it is consistent with other recently permitted combined cycle system sources in EPA Region IX, and 3) that the proposed source includes duct firing.

The permit states that the emission limit will be reduced to 2.0 ppmvd at 15% O_2, excluding periods of start-up and shutdown, after the first two years of operation. If the facility has not been able to reasonably and consistently meet a NO_x limit of 2.0 ppmvd, the facility is required to submit a written request to the Director prior to the two year anniversary, requesting a different limit not to exceed 2.5 ppmvd. The Administrator should be copied on this request. The Department will review the request and determine the final emission limit for the remaining permit term.

As noted above, operation of SCR systems can result in undesired emissions of unreacted NH_3, or ammonia slip. Other similar sources permitted in EPA Region IX have been limited to 10 ppmvd NH_3. Given that source is not in operation, the lower ammonia slip level in conjunction with the lower NO_x limit has not been demonstrated. Consequently, ADEQ is establishing a conditional ammonia slip emission limit of 10 ppmvd at 15% O_2 (24-hour average) for the first two years, with a similar demonstration period as NO_x, that may reduce the ammonia emission limit to 7.5 ppmvd (24-hr average).

3. *Carbon Monoxide (CO)*

CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_x during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

The applicant considered catalytic oxidation and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control both NO_x and CO, and the additional control of CO was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and is not considered further. An oxidation catalyst represents the most stringent control option, thus, no further analysis of control technologies is required.

In the original application and subsequent submittals, the applicant presented cost-effectiveness analyses for three levels of control, 4, 3, and 2 ppmvd. It was determined that 2 ppmvd was not economically feasible, and that 3 ppmvd is cost-effective and is proposed as BACT.

A comparison of the control systems considered by the applicant are presented and compared with previously permitted CO control systems taken from the RBLC in Table 10. A review of the RBLC data in Table 10 indicates that combined cycle projects have recently been permitted both with and without an oxidation catalyst.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce CO to 3 ppmvd at 15% O_2 with and without duct firing, on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

Table 9a. Summary of Top-Down BACT Impact Analysis Results For NO_x (SW501F)

					Economic Impacts			Environmental Impacts		Energy Impacts
Emission Unit	Control Alternative	Emissions (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (y/n)	Adverse Environ-mental Impacts (y/n)	Incremental Increase over Baseline (MMBtu/yr)
CTGSTK1	SCONOx @ 2.0ppmvd	864	791	91%	$5,917,133	$8,317.87	-	No	No	116,815
	SCR @ 2.0 ppmvd	864	791	91%	$2,324,763	$3,267.98	-	No	Yes	58,407
	SCR @ 2.5 ppmvd	864	779	89%	$2,182,943	$3,118.18	SCONOx - $330,303 SCR - $12,545	No	Yes	46,726

Table 9b. Summary of Top-Down BACT Impact Analysis Results For NO_x (GE7FA)

					Economic Impacts			Environmental Impacts		Energy Impacts
Emission Unit	Control Alternative	Emissions (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (y/n)	Adverse Environ-mental Impacts (y/n)	Incremental Increase over Baseline (MMBtu/yr)
CTGSTK1	SCONOx @ 2.0ppmvd	530	454	86%	$5,917,133	$8,317.87	-	No	No	116,815
	SCR @ 2.0 ppmvd	530	454	86%	$2,036,810	$4,489.00	-	No	Yes	58,407
	SCR @2.5 ppmvd	530	435	82%	$2,002,310	$4608.00	SCONOx - $204,227 SCR - $1,815	No	Yes	46,726

Table 10. CTG/HRSG BACT Comparison for CO

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		La Paz Generating Facility	CTG/HRSG	Oxidation Catalyst	3	ppmvd	BACT
WA-0288	9/4/01	Longview Energy Development	CTG/HRSG	Oxidation Catalyst	2	ppmv	BACT
WI-0114	1/13/95	LS Power	CTG	Good Combustion	2	ppmv	BACT
CT-0148	6/22/99	Lake Road Generating Company	CTG	Oxidation Catalyst	3	ppmv	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	Oxidation Catalyst	3	ppmv	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
CA	12/2/99	Sutter Power Plant	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
CA	12/18/01	Elk Hills Power Project	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
WI-0174	9/20/00	Badger Generating Co LLC	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
MI-0256	1/12/01	Covert Generating Co LLC	CTG/HRSG	Oxidation Catalyst	5	ppmv	BACT
CA	5/30/01	Contra Costa	CTG/HRSG	Oxidation Catalyst	6	ppmv	BACT
CA	10/27/00	Otay Mesa	CTG/HRSG	Oxidation Catalyst	6	ppmv	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	6	ppmv	BACT
FL-0225	8/14/01 Dft	El Paso Broward Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
FL-0226	9/11/01 Dft	El Paso Manatee Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
FL-0227	9/11/01 Dft	El Paso Belle Grade Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	Good Combustion	8.2	ppmv	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	Good Combustion	9	ppmv	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating STN	CTG	Combustion Controls	9	ppmv	BACT
FL-0223	11/4/99	Lake Worth Generating, LLC	CTG	Combustion Design	9	ppmv	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	9	ppmv	BACT
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion	9	ppmv	BACT
FL-0202	8/17/92	Orlando Cogen	CTG	Combustion Control	10	ppmv	BACT
MO-0049	8/19/99	Kansas City Power & Light	CTG/HRSG	Oxidation Catalyst	10	ppmv	BACT
MO-0056	3/30/99	Associated Electric Cooperative, Inc.	CTG	Good Combustion	10	ppmv	BACT
OK-0036	NG	Stephens Energy Facility	CTG/HRSG	NG	10	ppmv	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	Combustion Control	10	ppmv	BACT
PA-0160	10/10/00	Calpine Construction Finance Co.	CTG	None	10	ppmv	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Oxidation Catalyst	37	lb/hr	BACT

Table. 11a Summary of Top-Down BACT Impact Analysis Results For CO (SW501F)

					Economic Impacts			Environmental Impacts		Energy Impacts
Emission Unit	Control Alternative	Emissions (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental cost Effectiveness ($/ton)	Toxics Impact (y/n)	Adverse Environ-mental Impacts (y/n)	Incremental Increase over Baseline (MMBtu/yr)
CTGSTK1	SCONOx @ 2.0 ppmvd	242.7	207.79	86%	$5,734,746	$27,599	-	No	No	116,815
	Oxidation Catalyst @ 2.0 ppmvd	242.7	207.79	86%	$840,687	$4,045	-	No	No	17,522
	Oxidation Catalyst @ 3.0 ppmvd	242.7	190.33	78%	$740,819	$4,170	SCONOx- $295,037 Oxidation Catalyst - $5,866	No	No	11,681
	Oxidation Catalyst @ 4.0 ppmvd	242.7	172.87	71%	$711,771	$4,114	$1,781	No	No	11,681
	Oxidation Catalyst @ 5.0 ppmvd	242.7	155.41	64%	$677,880	$4,362	$1,948	No	No	9,345

Table. 11b Summary of Top-Down BACT Impact Analysis Results For CO (GE7FA)

					Economic Impacts			Environmental Impacts		Energy Impacts
Emission Unit	Control Alternative	Emissions (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Annualized Cost ($/yr)	Average Cost Effectiveness (c) ($/ton)	Incremental cost Effectiveness ($/ton)	Toxics Impact (y/n)	Adverse Environ-mental Impacts (y/n)	Incremental Increase over Baseline (MMBtu/yr)
CTGSTK1	SCONOx @ 2.0 ppmvd	262.10	221.86	85%	$5,917,134	$26,670	-	No	No	116,815
	Oxidation Catalyst @ 2.0 ppmvd	262.10	221.86	86%	$1,017,718	$4,587	-	No	No	17,522
	Oxidation Catalyst @ 3.0 ppmvd	262.10	201.86	77%	$930,761	$4,611	SCONOx-$295,037 Oxidation Catalyst -$5,866	No	No	11,681
	Oxidation Catalyst @ 4.0 ppmvd	262.10	181.83	69%	$868,302	$4,775	$1,781	No	No	11,681
	Oxidation Catalyst @ 5.0 ppmvd	262.10	161.83	62%	$829,912	$5,128	$1,948	No	No	9,345

4. *Volatile Organic Compounds (VOC)*

The proposed combustion turbines and duct burners are natural gas-fired combustion units. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air.

Combustion systems with poor control of the fuel to air ratio, poor mixing, and/or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines and duct burners incorporate state-of-the-art combustion technology, and both are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

The two most prevalent components of natural gas, methane (approximately 94% by volume) and ethane (approximately 4% by volume), are not defined as VOCs. The remaining portions of natural gas are propane and trace quantities of higher molecular weight hydrocarbons, all of which are nearly 100% combusted. The high energy efficiency of turbines and duct burners and low fraction of VOCs in natural gas result in a very low VOC emissions rate for the proposed new units. Additionally, the recombination of products of incomplete combustion is unlikely in well controlled turbine/duct burner systems because the conditions required for recombination are not present.

The applicant considered $SCONO_x$, catalytic oxidation, and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control NO_x, CO, and VOC, and the additional control of VOC was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and was not considered further. An oxidation catalyst represents the most stringent control option, thus, no further analysis of control technologies is required. Table 12 presents a comparison of the control systems considered by the applicant and previously permitted VOC control systems taken from the RBLC.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce VOC emissions to 2.5 ppmvd at 15% O_2 for the SW turbines and 4.5 ppmvd at 15% O_2 for the GE turbines, with and without duct firing, on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

5. *Sulfur Dioxide (SO_2)*

The proposed combustion turbines and duct burners will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., scrubbers) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the realizable emission reduction is far too small for this option to be cost-effective.

Table 12. CTG/HRSG BACT Comparison for VOC

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss Limi
		La Paz Generating Facility	CTG/HRSG	Oxidation Catalyst	2.5/4.
WI-0174	9/20/00	Badger Generating Co, LLC	CTG	Oxidation Catalyst	1.2
NJ-0043	3/28/02	Liberty Generating Station	CTG/HRSG	Oxidation Catalyst	1.7
PA-0184	10/10/00	Calpine Construction Finance Co, LP	CTG	Oxidation Catalyst	1.8
FL-0216	6/4/01	FPC - Hines Energy Complex, Power Block 2	CTG	Combustion Controls	2
PA-0191	4/18/02	Limerick Partners, LLC	CTG	Oxidation Catalyst	2.4
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Oxidation Catalyst	2.8
RI-0019	5/3/00	Reliant Energy Hope Generating Facility	CTG/HRSG	Oxidation Catalyst	2.9
FL-0124	11/22/99	Oleander Power Project	CTG	Good Combustion	3
PA-0192	10/20/01	Lower Mount Bethel Energy, LLC	CTG	Oxidation Catalyst	3
MA-0025	8/4/99	ANP Bellingham Energy Co	CTG	Oxidation Catalyst	3.5
MA-0024	4/16/99	ANP Blackstone Energy Co	CTG	Oxidation Catalyst	3.5
MI-0267	6/7/01	Renainssance Power, LLC	CTG/HRSG	Oxidation Catalyst	4
MI-0327	12/2/01	Indeck-Niles, LLC	CTG/HRSG	NG	4
MI-0303	7/26/01	Midland Cogeneration	CTG/HRSG	Oxidation Catalyst	4.2
SC-0061	4/9/01	Columbia Energy, LLC	CTG	Good Combustion	4.5
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Oxidation Catalyst	5.2
AL-0185	7/12/02	Barton Shoals Energy	CTG/HRSG	Good combustion	5.3
OK-0046	5/17/01	Thunderbird Power Plant	CTG/HRSG	Combustion Controls	7
SC-0063	7/3/01	Genpower Anderson LLC	CTG/HRSG	Good Combustion	7
TX-0234	1/8/02	Edinburg Energy Limited Partnership	CTG	NG	9
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	3
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	3.7
OK-0044	8/16/01	Smith Pocola Energy Project	CTG/HRSG	Good Combustion	0.001
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG/HRSG	Good Combustion	0.001
PA-0188	3/28/02	Fairless Energy LLC	CTG	Oxidation Catalyst	0.002
AL-0179	10/3/01	Tenaska Talladega Generating Station	CTG/HRSG	Good Combustion	0.007

The use of natural gas is proposed as BACT for SO_2. As discussed under the NSPS section, SO_2 emissions will be below the regulatory limits required by Subpart GG (there are no SO_2 requirements in Subpart Da for natural gas fired units). Table 13 presents a comparison of the SO_2 BACT limits proposed by the applicant and previously permitted SO_2 limits taken from the RBLC. As shown in Table 13, there is no precedent for use of post-combustion control of SO_2 on combined cycle units.

There are no known applications of add-on controls for the purpose of controlling SO_2 from natural gas-fired units. Therefore, the applicant has demonstrated that the use of good combustion practices and natural gas represents BACT for SO_2. The fuel will be limited by the maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf) and a limit of .0021 lb/MMBtu.

B. Cooling Towers

Particulates are emitted from cooling towers when small droplets of cooling water, called drift, are emitted and evaporate. The dissolved and suspended materials in the drift can become airborne particles when the water around them evaporates. The size distribution of the emitted particulates includes particles in both the PM and PM_{10} range.

The primary factor that controls the amount of PM_{10} from the cooling tower is the droplet drift rate. A droplet drift rate of 0.0005 percent (achieved through the use of high efficiency drift eliminators on the cooling tower) was determined to represent BACT for the cooling towers. The BACT limit is based on vendor guarantees and is consistent with the most stringent limits listed in the RBLC.

ADEQ also requested the applicant consider a dry, air-cooled condenser in lieu of a wet cooling tower as the top control option in its cooling tower BACT analysis. The applicant provided cost data for such a dry system that demonstrated that the technology was not economically feasible when compared to a wet cooling tower. Consequently, the Department concludes that the high efficiency drift eliminators with an efficiency of 0.0005 percent are BACT for PM_{10} for the cooling towers.

C. Auxiliary Boiler

The proposed facility will either include a 55.34 MMBtu/hr auxiliary boiler or a 41 MMBtu/hr boiler depending on the type of turbine that is purchased. Due to the size of the boilers, it would be economically impractical to install any kind of control device.

The emissions from the auxiliary boiler are so low that potential emission reductions from controls are not cost-effective. As demonstrated in the BACT analysis for NO_x, the largest emission reduction is 0.52 tpy (considering a 98.6% reduction). At such a reduction, the capital cost of a control system would need to be quite inexpensive to be cost-effective, and is below the cost of available controls. Consequently, the application of control technologies are not cost-effective and low-NO_x burners are determined as BACT for NO_x.

Emissions of CO and VOC are also low. As a result, an add-on control device such as an oxidation catalyst would not be cost-effective. As with the combined-cycle units, no add-on control devices have been identified for the control of PM_{10} or SO_2 from the auxiliary boiler. Combustion controls and the use of natural gas are considered BACT for CO, VOC, PM_{10}, and SO_2 from the auxiliary boiler.

Table 13. CTG/HRSG BACT Comparison for SO_2

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		La Paz Generating Facility	CTG/HRSG	Low Sulfur Fuels	.0021	lb/MMBtu	BACT
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG	Low Sulfur Fuels	0.0006	lb/MMBtu	BACT
PA-0196	8/7/01	SWEC-Falls Township	CTG	NG	0.002	lb/MMBtu	OTHER
AL-0168	1/12/01	GenPower Kelley LLC	CTG/HRSG	NG	0.002	lb/MMBtu	BACT
PA-0188	3/28/02	Fairless Energy LLC	CTG	NG	0.002	lb/MMBtu	OTHER
OK-0072	5/6/02	Redbud Power Plant	CTG	Low Sulfur Fuel - Natural Gas	0.003	lb/MMBtu	BACT
NJ-0043	3/28/02	Liberty Generating Station	CTG/HRSG	Use of Natural Gas	0.004	lb/MMBtu	OTHER
OK-0046	5/17/01	Thunderbird Power Plant	CTG/HRSG	Natural Gas	0.005	lb/MMBtu	BACT
RI-0019	5/3/00	Reliant Energy Hope Generating Facility	CTG/HRSG	Clean Fuel - Natural Gas	0.0054	lb/MMBtu	BACT
PA-0184	10/10/00	Calpine Construction Finance Co, LP	CTG	Good Combustion, Sulfur Content	0.0056	lb/MMBtu	OTHER
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion, Natural Gas	0.0057	lb/MMBtu	BACT
OK-0051	10/1/99	Green Country Energy Project	CTG/HRSG	Use of Natural Gas	0.006	lb/MMBtu	BACT
AL-0185	7/12/02	Barton Shoals Energy	CTG/HRSG	Natural Gas Only	0.007	lb/MMBtu	BACT
OK-0044	8/16/01	Smith Pocola Energy Project	CTG/HRSG	Use of Natural Gas	0.216	lb/MMBtu	BACT
PA-0192	10/20/01	Lower Mount Bethel Energy, LLC	CTG	NG	0.0027	ppmv	LAER
PA-0191	4/18/02	Limerick Partners, LLC	CTG	Low Sulfur Fuel	0.8	ppmv	OTHER
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Natural Gas	2.1	lb/hr	BACT
TX-0234	1/8/02	Edinburg Energy Limited Partnership	CTG	NG	4	lb/hr	BACT
IN-0086	5/9/01	Mirant Sugar Creek, LLC	CTG/HRSG	Low Sulfur Natural Gas	4.2	lb/hr	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Use of Natural Gas	5.8	lb/hr	BACT
SC-0063	7/3/01	Genpower Anderson LLC	CTG/HRSG	Low Sulfur Fuel	6	lb/hr	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Low Sulfur Natural Gas	11	lb/hr	BACT
MS-0051	11/13/01	LSP-Batesville Generation Facility	CTG/HRSG	Natural Gas	15	lb/hr	BACT

D. Fire Water Pumps and Emergency Generators

If the Permittee installs SW501F turbines, the proposed facility will include two generator sets. Each generator set will be made up of one emergency generator and one fire water pump.

If the Permittee installs GE7FA turbines, the proposed facility will include one generator set. This generator set will be made up of one emergency generator and two fire water pumps.

Each generator set will be limited to 500 hours of operation per year. This limitation on the hours of operation results in minimal emissions. As a result, BACT for the engines was determined to be good combustion control as provided by modern engine control systems.

VI. MONITORING REQUIREMENTS

A. Compliance Assurance Monitoring (CAM)

Pursuant to 40 CFR 64.2(b)(iii), the facility is not subject to CAM for NO_x because it is subject to Acid Rain Program requirements, and is not subject to CAM for CO because the facility will install a CEMS to measure CO emissions.

B. Combined Cycle Systems

The Combined Cycle Systems may be operated in combined cycle operation and may only burn pipeline quality natural gas.

PM: The units are subject to a PM_{10} emission limitation resulting from the use of BACT. Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Opacity: The Combined Cycle Systems are subject to the opacity standard of 10% as is consistent with previous permitting projects in the State (i.e., Griffith Energy). Natural gas is a clean burning fuel and operation of these types of units generally indicate that opacity problems are rare.

NO_x: The units are subject to a NO_x emissions limitation resulting from the use of BACT. The source is required to operate, certify, maintain, and calibrate compliance CEMS for NO_x. The CEMS will comply with the applicable requirements of 40 CFR Part 75. A Relative Accuracy Test Audit (RATA) is required annually for the monitors. The source is also required to develop an Operations and Maintenance plan for the SCR system.

CO: The units are subject to a CO emissions limitation resulting from the use of BACT. The source is required to operate, certify, maintain, and calibrate compliance CEMS for CO. The CEMS will comply with the applicable provisions of 40 CFR Part 60 and 40 CFR Part 75. A RATA is required annually for the monitors.

SO_2: The units are subject to a limit of 0.75 grains of sulfur/100 dscf in the natural gas and a limit of 5.1 (GE configuration) and 4.6 (SW configuration) pounds of SO_2 per hour. This limit will be demonstrated by the Permittee maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas.

Emissions will be determined using the sulfur content in the fuel and monitored fuel usage data.

VOC: The units are subject to a VOC emissions limitation due to the additional benefits resulting from the use of BACT to control CO emissions. Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Ammonia: The units are subject to an ammonia slip emission limit. The source is required to operate, certify, maintain, and calibrate ammonia flow meters on each SCR unit to monitor the ammonia injection rate.

Flow and Diluent: As per 40 CFR Part 75, fuel flow meters are required on each fuel line to monitor the unit-specific fuel flow to the combustion turbines and duct burners. O_2 (or CO_2) diluent gas monitors are required on each combined cycle system. The monitors will comply with the applicable provisions of 40 CFR Part 60 (Appendices B and F) and 40 CFR Part 75.

VII. TESTING REQUIREMENTS

Performance testing is one component used to demonstrate compliance with the emission rates in the permit. Specifications regarding the test plan, sampling facilities, and reports are included in the General Provisions (Attachment A) of the permit. Test methods are specified in the permit and testing will be performed at full load and at reduced load conditions.

A. Combined Cycle Systems with Duct Firing

The La Paz Generating Facility is required to perform initial performance tests for PSD pollutants. Annual stack testing for NO_x and CO is not specified separately because annual testing will be conducted as part of the Relative Accuracy Test Audits (RATA) for the CEMS. Performance testing for ammonia at full load with duct firing will be conducted initially and every two years thereafter. Catalyst life expectancy for the SCR is typically given as three years. Therefore, performing a stack test every two years will determine if there is early catalyst degradation. An initial performance test and annual tests thereafter for PM_{10} and VOC will be used to demonstrate compliance with the PM_{10} and VOC emission limits. An initial performance test for SO_2 will be used because this is a PSD pollutant to demonstrate compliance with the SO_2 lb per hour emission limitation. Testing will be performed at full load and at reduced load conditions.

B. Auxiliary Boilers

La Paz Generating Facility is required to perform an initial performance test for NO_x, CO, SO_2, VOC, and PM_{10} emissions from the auxiliary boiler.

VIII. IMPACTS TO AMBIENT AIR QUALITY

Air Quality Modeling for the La Paz Generating Station

A. General

The air quality modeling required of this facility in support of its permit application can be characterized as thorough, complete, within Arizona Department of Environmental Quality and Federal guidelines, and fully demonstrative that its proposed emissions will not lead to the violation of any kind of air quality standard or guideline. This section describes the modeling in some detail, and summarizes the results so the reader can interpret the predicted concentrations in terms of the regulatory guidelines. Overly technical terms will be explained in the narrative.

Air quality modeling was performed to compare the predicted concentrations from the facility with three types of standards or guidelines. First, this new source was large enough to come under the umbrella of the Federal PSD regulations. These regulations protect both Class I wilderness areas (designated Wilderness areas and National Parks) and Class II wilderness areas (those already attaining all National Ambient Air Quality Standards (NAAQS) from the emissions of a proposed source. PSD air quality modeling typically involves both near-field (close to the source) and long-distance transport considerations: to both Class I and Class II Wilderness Areas. Second, the emissions were simulated to predict concentrations of all pollutants covered by the NAAQS. Third, the concentrations of several pollutants that do not have an air quality standard but do have an Arizona Ambient Air Quality Guideline (AAAQG) were also simulated.

B. Air Quality Model

An air quality model takes the amount of emissions and the ventilation capacity of the air near the surface and predicts the concentrations of air pollutants that would occur from these emissions. The model applied to this facility is called Industrial Source Complex Version 3 (ISC3) with the Building Profile Input Program (BPIP). This model, or its predecessors, has over 20 years of regulatory use and is fully approved by the United States Environmental Protection Agency. It is considered the standard model to predict concentrations of pollutants from proposed large point sources, such as this generating plant. In field evaluation tests and in comparison with other numerical models, the ISC3 model consistently produces answers that are higher than the measurements and many other models. These consistently high predictions ensure that results from the ISC3 model are inherently conservative: i.e. the results will be over rather than under estimates of real-world concentrations. This conservatism ensures compliance with the various air quality concentration standards and guidelines.

C. Meteorology and Background Concentrations

For a model such as ISC3 to work, meteorological data are necessary. This facility was required to collect wind speed and wind information on site for an entire year. These surface wind measurements, when coupled with the nearest upper air measurements (from Tucson), provide the meteorological basis for this modeling exercise. No data are better than those collected on site.

Background concentrations of gaseous pollutants were estimated from the Department's statewide network of air pollution monitors. But, for particles 10 microns and smaller, known as PM_{10}, the facility was required to make on-site measurements for an entire year. These measurements supplied the background PM_{10} concentrations.

D. Emissions

Any numerical model that predicts concentrations from a facility must have its emission rates. In the case of the modeling performed at the La Paz Generating Facility, both the entire facility's emissions and emissions from major point sources nearby were considered. First, for the facility, the worst case emissions from three different ambient temperatures and three different load percentages were calculated for the combined-cycle gas turbines. These calculations were done twice: once for General Electric turbines and once for Siemens-Westinghouse turbines. The air quality model results, discussed below, are given for the emissions from each kind of turbine. The maximum hourly and annual PM_{10} emissions from the cooling towers were based on their continuous operation. The auxiliary boiler, used only during periods of turbine shutdown, was assumed to operate continuously, providing much higher annual emissions than will actually occur. Emissions of some pollutants can be higher during startup and shutdown. A conservative figure of 300 such startups and shutdowns was assumed and their emissions calculated. Hourly carbon monoxide emission rates for start-up were calculated so that the 1-hour carbon monoxide ambient air quality standards could be modeled.

Second, emissions from plants within 50 kilometers were also taken into account in the air quality modeling. These sources included Sonas soil treating (Vicksburg), Phoenix Agro, Harquahala Generating Station, Chickasha Cotton Oil Co., Mesquite Power Plant, and Arlington Valley Power Plant.

E. Results

The results of the ISC model predictions for these worst-case emissions with the on-site meteorological data are given as concentrations: micrograms per cubic meter ($\mu g/m^3$), with the various guideline or standard concentration, and the percentage of the guideline or standard. Preliminary modeling for carbon monoxide, including hourly start-up emissions, showed that carbon monoxide predicted concentrations were less than the Significant Impact Level. This means that a full NAAQS analysis for carbon monoxide was not necessary. Three other pollutants were significant, so full NAAQS analyses were performed for nitrogen oxides, sulfur dioxide, and particulates (PM_{10}). Consider Tables 14a and 14b, below, which give the predictions for three pollutants.

Table 14a. Model Predictions of Air Pollutant Concentrations from the La Paz Generating Station: NAAQS Pollutants – with GE Turbines

Pollutant	Avg Period	Pred Max	Backgrnd	Impact	PSD inc	% PSD	NAAQS	%NAAQS
NOx	annual	2.6	17	19.6	25	10.4	100	19.60
SO2	3 hr	49.4	31	80.4	512	9.65	1300	6.18
	24 hr	1.9	10	11.9	91	2.09	365	3.26
	annual	0.5	4	4.5	20	2.50	80	5.63
PM_{10}	24 hr	8.6	65	73.6	30	28.67	150	49.07
	annual	1.2	21	22.2	17	7.06	50	44.40

(All units are $\mu g/m^3$)

Table 14b. Model Predictions of Air Pollutant Concentrations from the La Paz Generating Station: NAAQS Pollutants – with SW Turbines

Pollutant	Avg Period	Pred Max	Backgrnd	Impact	PSD inc	% PSD	NAAQS	%NAAQS
NOx	annual	4.6	17	21.6	25	18.40	100	21.60
SO2	3 hr	82.2	31	113.2	512	16.05	1300	8.71
	24 hr	3.2	10	13.2	91	3.52	365	3.62
	annual	0.9	4	4.9	20	4.90	80	6.13
PM10	24 hr	7.4	65	72.4	30	24.67	150	48.27
	annual	1.6	21	22.6	17	9.41	50	45.20

The three pollutants are oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particles 10 microns and smaller (PM_{10}). The "pred max", or predicted maximum is what the model predicts. These maxima were all within 2 kilometers of the source. The "backgrnd" or background value has been discussed. The sum of the prediction and the background is the impact. The PSD increment is set in Federal regulations, and its percentage is the predicted maximum divided by the increment, times 100 percent. The overall impact, which is the sum of the predicted maximum and the background, divided by the federal air quality standard, or NAAQS, times 100% , gives the percentage of the NAAQS. These data show that neither the PSD increment nor the NAAQS is approached for any pollutant for any averaging time. The closest an increment or standard comes to being exceeded is for PM_{10}, whose 24-hour predicted plus background value is 49% of the standard.

Predicted concentrations of 28 toxic compounds -- metals, organic compounds, acids – were also calculated from the maximum toxic emission rates and with the ISC model. Tables 15a and 15b provides those results.

Table 15a. Hazardous Air Pollutant Predictions for the La Paz Generating Station - GE Turbines

	One-Hour			24-hour			Annual		
Pollutant	Impact	AAAQG	%	Impact	AAAQG	%	Impact	AAAQG	%
1,3-butadiene	1.70E-03	7.2	0.024	2.60E-04	1.9	0.014	1.10E-05	6.70E-02	0.016
acetaldehyde	1.50E-01	2.30E+02	0.065	2.20E-02	1.40E+02	0.016	1.70E-03	5E-01	0.340
acrolein	3.20E-02	6.70	0.478	4.50E-03	2	0.225			
ammonia				7.6	1.40E+02	5.429			
benzene	6.60E-01	6.30E+02	0.105	7.10E-02	5.10E+01	0.139	1.10E-02	1.40E-01	7.857
benzo(a)anthracene	5.70E-04	7.90E-01	0.072	6.50E-05	2.10E-01	0.031	9.10E-06	5.70E-04	1.596
benzo(a)pyrene	2.60E-04	7.90E-01	0.033	2.90E-05	2.10E-01	0.014	3.90E-06	5.70E-04	0.684
dibenz(a,h)anthracene	3.60E-04	6.70E-01	0.054	4.20E-05	2.10E-01	0.020	5.40E-06	5.70E-04	0.947
dichlorobenzene	6.90E-03	2.50E+02	0.003	1.10E-03	6.60E-01	0.167	9E-05	1.80E-01	0.050
ethylbenzene	1.30E-01	5.30E+03	0.002	1.90E-02	3.50E+03	0.001			
formaldehyde	7.10E-01	2E+01	3.550	1.10E-01	1.20E-01	91.667	8.10E-03	8E-02	10.125
hexane	4.4	5.30E+03	0.083	7.50E-01	1.40E+03	0.054			
naphthalene	1.10E-01	6.30E+02	0.017	1.20E-02	4E+02	0.003			
propylene oxide	1.10E-01	1.50E+03	0.007	1.70E-02	4E+02	0.004	7.10E-04	2	0.036
sulfuric acid mist	6.8	2.20E+01	30.909	1	7.5	13.333			
toluene	7.40E-01	4.70E+03	0.016	1E-01	3E+03	0.003			
xylenes	4E-01	5.50E+03	0.007	5.40E-02	3.50E+03	0.002			
arsenic	1.30E-03	2.80E-01	0.464	2E-04	7.30E-02	0.274	1.60E-05	2E-04	8.000
barium	2.50E-02	1.50E+01	0.167	4E-03	4	0.100			
beryllium	6.90E-05	6E-02	0.115	1.10E-05	1.60E-02	0.069	9E-07	5E-04	0.180
cadmium	6.30E-03	1.7	0.371	1E-03	1.10E-01	0.909	8.20E-05	2.90E-04	28.276
chromium	8E-03	1.10E+01	0.073	1.30E-03	3.8	0.034			
copper	4.90E-03	2.3	0.213	7.80E-04	7.50E-01	0.104			
manganese	2.20E-03	2.50E+01	0.009	3.50E-04	8	0.004			
mercury	1.50E-03	1.5	0.100	2.40E-04	4E-01	0.060			
nickel	1.20E-02	5.7	0.211	1.90E-03	1.5	0.127	1.60E-04	4E-03	4.000
selenium	1.40E-04	6	0.002	2.20E-05	1.6	0.001			
vanadium	1.30E-02	1.5	0.867	2.10E-03	4E-01	0.525			

(Units are $\mu g/m^3$)

Table 15b. Hazardous Air Pollutant Predictions for the La Paz Generating Station - SW Turbines

	One-Hour			24-hour			Annual		
Pollutant	Impact	AAAQG	%	Impact	AAAQG	%	Impact	AAAQG	%
1,3-butadiene	1.50E-03	7.20E+00	0.021	2.40E-04	1.9	0.013	1.00E-05	6.70E-02	0.015
acetaldehyde	1.60E-01	2.30E+02	0.070	1.20E-02	1.40E+02	0.009	1.80E-03	5.00E-01	0.360
acrolein	3.30E-02	6.70E+00	0.493	4.50E-03	2	0.225			
ammonia	4.20E+01			6.3	1.40E+02	4.500			
benzene	1.00E+00	6.30E+02	0.159	1.10E-01	5.10E+01	0.216	1.80E-02	1.40E-01	12.857
benzo(a)anthracene	8.50E-04	7.90E-01	0.108	9.20E-05	2.10E-01	0.044	1.50E-05	5.70E-04	2.632
benzo(a)pyrene	3.80E-04	7.90E-01	0.048	4.10E-05	2.10E-01	0.020	6.20E-06	5.70E-04	1.088
dibenz(a,h)anthracene	5.20E-04	6.70E-01	0.078	5.80E-05	2.10E-01	0.028	8.50E-06	5.70E-04	1.491
dichlorobenzene	1.40E-02	2.50E+02	0.006	1.20E-03	6.60E-01	0.182	1.20E-04	1.80E-01	0.067
ethylbenzene	1.20E-01	5.30E+03	0.002	1.80E-02	3.50E+03	0.001			
formaldehyde	8.00E-01	2.00E+01	4.000	5.70E-02	1.20E-01	47.500	8.00E-03	8.00E-02	10.000
hexane	1.60E+01	5.30E+03	0.302	1.00E+00	1.40E+03	0.071			
naphthalene	1.70E-01	6.30E+02	0.027	1.80E-02	4E+02	0.005			
propylene oxide	1.00E-01	1.50E+03	0.007	1.60E-02	4E+02	0.004	6.90E-04	2.00E+00	0.035
sulfuric acid mist	7.10E+00	2.20E+01	32.273	1.1	7.5	14.667			
toluene	8.50E-01	4.70E+03	0.018	1E-02	3E+03	0.000			
xylenes	4.70E-01	5.50E+03	0.009	6.00E-02	3.50E+03	0.002			
arsenic	2.60E-03	2.80E-01	0.929	2E-04	7.30E-02	0.301	2.20E-05	2.00E-04	11.000
barium	5.30E-02	1.50E+01	0.353	5E-03	4	0.113			
beryllium	1.40E-04	6.00E-02	0.233	1.20E-05	1.60E-02	0.075	1.20E-06	5.00E-04	0.240
cadmium	1.30E-02	1.70E+00	0.765	1E-03	1.10E-01	1.000	1.10E-04	2.90E-04	37.931
chromium	1.70E-02	1.10E+01	0.155	1.40E-03	3.8	0.037			
copper	1.00E-02	2.30E+00	0.435	8.60E-04	7.50E-01	0.115			
manganese	4.50E-03	2.50E+01	0.018	3.90E-04	8	0.005			
mercury	3.10E-03	1.50E+00	0.207	2.60E-04	4E-01	0.065			
nickel	2.50E-02	5.70E+00	0.439	2.10E-03	1.5	0.140	2.10E-04	4.00E-03	5.250
selenium	2.90E-04	6.00E+00	0.005	2.40E-05	1.6	0.002			
vanadium	2.80E-02	1.50E+00	1.867	2.30E-03	4E-01	0.575			

Each of the "impact" numbers is the prediction from the ISC model. Each of the "AAAQG" numbers is that value specified by the Arizona Department of Health Services as the "Arizona Ambient Air Quality Guideline." These guideline values are determined by surveying the toxicological literature and by applying the latest short-term and long-term concentration values to ensure that (1) either one-hour or 24-hour exposure to that concentration does not cause short-term adverse health effects; and (2) that a life-time of exposure to the "annual" standard does not lead to an increased incidence of cancer in excess of one case per million population. The "%" numbers are the predictions expressed as a percentage of the appropriate AAAQG. For those readers uncomfortable with scientific notation, the expression of a decimal fraction as an exponential goes as follows:

0.0003 becomes 3E-04

0.003 becomes 3E-03

0.03 becomes 3E-02

0.3 becomes 3E-01

3 stays as 3

30 becomes 3E01

300 becomes 3E02, etc.

What the "%" numbers show is that for the one-hour averaging period, most air toxics are predicted to be less than one percent of the AAAQG, the exceptions being formaldehyde at 4.0%, and sulfuric acid mist at 32.3%. A similar distribution holds for the 24-hour predictions, all of which are less than one percent of the AAAQG, except for formaldehyde at 91.7% and sulfuric acid mist at 14.7%. Six different compounds exceed this one percent of AAAQG level at the annual averaging period: benzene (12.8%), benz(a)anthracene (2.6%), formaldehyde (10.1%), arsenic (11.0%), cadmium (37.9%), and nickel (5.2%). Given the conservative nature of the model and the conservatism built into the AAAQGs, and considering that the location of all these predicted maxima are very close to, if not on the actual fence line of the facility, this analysis demonstrates that air toxic concentrations predicted for the facility do not pose a public health problem.

The third type of air quality modeling assesses the impact of the plant's emissions at considerable downwind distances, specifically at seven different Class II wilderness areas. Several such assessments were done, including predicting the concentrations of gaseous NAAQS pollutants, the deposition of sulfate and nitrate, the effects of these pollutants on vegetation, and the visibility degradation that might be expected from the facility. The gaseous pollutant concentrations were low in these seven wilderness areas, the sulfate and nitrate deposition was also low, and the effects on vegetation well below the screening limits. This discussion is devoted to the last of the aforementioned effects -- visibility. These assessments were done with what's called a Level 2 screening analysis with the numerical model VISCREEN. This model simulates the visibility degradation by first transporting the particulate and nitrogen oxides emissions from the plant directly to the wilderness area (real-world surface wind speeds and directions are not used here). Simplified chemistry within the model converts the gaseous nitrogen oxides to particulate nitrate, a species that along with general particulate matter, scatters light. With background conditions factored in, the degree of predicted plume contrast seen by an observer in the wilderness is calculated.

Tables 16a and 16b give the wilderness areas, their directions, and their distances from the La Paz Generating Facility. Both the closest and furthest distance in each wilderness area from the plant are given. The observer then is said to be at the minimum distance, looking towards the maximum distance. The model calculates the predicted change in general contrast and in color contrast that the observer would see looking at the plume against both the sky and the terrain. Based on the background concentrations the critical values of general and color contrast are also calculated. The critical value is that optical value that would have to be present for the observer to be able to perceive the plume or its effects. What the table shows is the predicted value as a percentage of the critical value.

Table 16a. Visibility Degradation Analysis for Seven Wilderness Areas Near the La Paz Generating Facility - GE Turbines

Area	Distance From Plant (km)		Direction	% Critical Value	
	Minimum	Maximum		Color	Contrast
Signal Mountain	49.9	56.6	SE	62.9, terrain	24.0, sky
Eagletail Mountains	6.8	25.9	SSW	75.1, terrain	22.2, sky
New Water Mountains	46.3	66.9	W	53.1, terrain	26.0, sky
Harcuvar Mountains	47.3	58.6	N	1.6, terrain	1.0, sky
Harquahala Mountains	25.7	33.2	NNE	45.2, terrain	16.0, sky
Hummingbird Springs	23.0	34.0	NE	39.9, terrain	16.0, sky
Big Horn Mountains	16.1	30.0	ENE	46.2, terrain	20.0, sky

Table 16b. Visibility Degradation Analysis for Seven Wilderness Areas Near the La Paz Generating Facility -SW Turbines

Area	Distance From Plant (km)		Direction	% Critical Value	
	Minimum	Maximum		Color	Contrast
Signal Mountain	49.9	56.6	SE	50.9, terrain	20.0, sky
Eagletail Mountains	6.8	25.9	SSW	61.5, terrain	17.8, sky
New Water Mountains	46.3	66.9	W	42.9, terrain	20.0, sky
Harcuvar Mountains	47.3	58.6	N	1.3, terrain	0.5, sky
Harquahala Mountains	25.7	33.2	NNE	36.5, terrain	14.0, sky
Hummingbird Springs	23.0	34.0	NE	32.2, terrain	14.0, sky
Big Horn Mountains	16.1	30.0	ENE	37.4, terrain	16.0, sky

Note that none of the color or general contrast critical values has been exceeded. The highest is 75.1% and the second highest 62.9%, meaning, that at its most conspicuous, the plume from this facility would be below the threshold of perceptibility at all seven of the wilderness areas.

F. Conclusions

Air quality modeling of the proposed La Paz Generating Facility has demonstrated compliance with the NAAQS, with PSD Class II increments, with the AAAQGs, and with the various Class II Wilderness guidelines, especially visibility. The modeling was based on one year of on-site meteorological and PM_{10} data; relied on maximum expected emission rates from the combustion turbines and other equipment; and used numerical models approved by the United States EPA. The ambient air quality near and downwind of this plant will continue to meet standards and guidelines, but will be degraded, as a result of its emissions.

IX. INSIGNIFICANT ACTIVITIES

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PURSUANT TO A.A.C. R18-2-101.57
1	Building HVAC Exaust Vents
2	Turbine Compartment Ventilation Exhaust Vents
3	Sanitary Sewer Vents
4	Compressor Air Systems
5	Turbine Lube Oil Vapor Extractors and Lube Oil Mist Eliminator Vents
6	Steam Drum Safety Relief Valve Vents
7	Building Air Conditioning Units
8	Emergency Diesel Fire Pump Fuel Storage Tanks
9	Sulfuric Acid Storage Tank Vents
10	Various Steam Release Vents
11	Welding Equipment
12	Lab Hood Vents
13	Water Wash System Storage Tank Vents
14	Neutralization Basin
15	Sodium Hypochlorite Storage Tanks
16	Hydrazine Storage TanksVents
17	Fuel Purge Vents
18	Oil/Water Separator Waste Oil Collection Tanks
19	Condenser Vacuum Pump Vents
20	Sodium Hydroxide Tank

X. LIST OF ABBREVIATIONS

AAAQG	Arizona Ambient Air Quality Guideline
A.A.C.	Arizona Administrative Code
ADEQ	Arizona Department of Environmental Quality
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BPIP	Building Profile Input Program
CAM	Continuous Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
DLN	Dry Low-NO_x
dscf	Dry Standard Cubic Foot
EPA	Environmental Protection Agency
^oF	Degrees Fahrenheit
FERC	Federal Energy Regulatory Commision
GE	General Electric
hr	Hours
H_2	Hydrogen
H_2O	Water
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
hp	Horsepower
ISC3	Industrial Source Complex Version 3
ISO	International Standard Operation
lb	Pounds
lb/hr	Pound per Hour
lb/MMBtu	Pounds per Million British Thermal Units per Hour
$\mu g/m^3$	Microgram per Cubic Meter
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatt
N/A	Not Available
NA	Not Applicable
NAAQS	National Ambient Air Quality Standard
N_2	Nitrogen
NH_3	Ammonia
NO	Nitrogen Oxide
NO_x	Nitrogen Oxides
NO_2	Nitrogen Dioxide
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter Nominally less than 10 Micrometers

ppm . . . . Parts per Million
ppmvd . . . . Parts per Million by Dry Volume
PSD . . . . Prevention of Significant Deterioration
PTE . . . . Potential-to-Emit
RBLC . . . . RACT/BACT/LAER Clearinghouse
SCR . . . . Selective Catalytic Reduction
SNCR . . . . Selective Non-Catalytic Reduction
SO_x . . . . Sulfur Oxides
SO_2 . . . . Sulfur Dioxide
SO_3 . . . . Sulfur Trioxide
STG . . . . Steam Turbine Generator
SW . . . . Siemens Westinghouse
TDS . . . . Total Dissolved Solids
TPY . . . . Ton per Year
TSP . . . . Total Suspended Particulates
USGS . . . . United States Geological Services
VOC . . . . Volatile Organic Compound
yr . . . . Year